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MINERAL PROPERTY ECONOMICS

OIL SHALE

by

Ray A. Brady

U.S. Geological Survey

Area Oil Shale Office

Grand Junction, Colorado

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ABSTRACT

The economic evaluation of oil-shale properties requires an understanding of the geology of the deposits, geophysical and geological methods used to evaluate those deposits, and the ultimate mining and shale-oil extraction processes that determine the resource recovery.

The Eocene Green River Formation deposits in Colorado, Utah, and Wyoming contain the largest resources of shale oil in the world. The Piceance Creek basin of Colorado contains about 600 billion barrels of shale oil in high-grade oil-shale beds that yield at least 25 gallons of shale oil per ton. The Parachute Creek Member of the Green River Formation in the Piceance Creek basin contains the richest oil-shale deposits. This

member is divided into upper and lower oil-shale zones and into rich and lean oil-shale zones.

The Mahogany ledge (zone) in the lower part of the upper zone of the Parachute Creek Member consists almost entirely of rich oil shale. The Piceance Creek basin is a large depositional and structural basin with a well-defined system of northwest- and northeast-trending near-vertical joint sets.

Exploration methods used to evaluate oil-shale deposits include aerial photography, photogeologic and surface geologic mapping, core-hole lithologic logs, geophysical logs, and core samples. Core samples provide shale-oil yields, nahcolite and extractable alumina analyses, and rock mechanics data. These data are incorporated into the evaluation of the oil-shale deposit. Evaluation and determination of the total oil-shale, nahcolite and dawsonite resources within a deposit require the compilation of detailed geologic maps, cross sections, structure contour maps, histograms, and isopach, isograde, and isoresource maps.

Resource recovery is determined by the mining and retorting systems used to develop the oil-shale deposit. An oil-shale deposit can be developed by either surface or underground mining techniques. Resource recovery and mining costs vary with the selection of a specific mining method. Mining methods discussed include open pit, room-and-pillar, chamber-and-pillar, sublevel stoping, and block caving. Retorting techniques include surface retorting, true in-situ (in place) retorting, and modified in-situ retorting.

Resource recovery varies with the selection of a specific retorting system. The principal surface retorting systems considered for early commercial use in the United States include the Gas Combustion retort, Paraho process, Union Oil Company retorts, TOSCO II retort, Lurgi-Ruhrgas process, Petrosix process, and McDowell-Wellman process. True in-situ retorting is divided into processes that use natural permeability and processes that create artificial permeability in the oil-shale deposit. In modified in-situ retorting, underground rubble chambers are developed by conventional mining operations. Various mining systems for modified in-situ development result in a broad range of areal extraction ratios and retort efficiencies that significantly affect the recoverable barrels of shale oil.

The value of recovered shale oil is determined by the economics of the shale-oil production facilities. The capital investment required for an oil-shale operation is directly affected by oil-shale grade, production rate, and mining and retorting methods. The rate of return on an investment for an oil-shale development is a function of the dollar value (selling price) of the shale-oil product. At a 15 percent rate of return, the selling price (1976 dollars) of shale oil for various mining and retorting systems ranges from $10 to $15. This is compared to the 1977 average world oil price of $14.50 per barrel. Shale oil is entitled to receive the world price for oil in the United States. That price can be considered as the maximum market value for a commercially produced barrel of shale oil and can be used to determine the value of an oil-shale property.

INTRODUCTION

Oil shale is a potential energy resource of the future. The world's largest known oil-shale resources occur in the organic-rich dolomitic marlstone deposits of the Eocene Green River Formation of Colorado, Utah, and Wyoming. Oil shale is a fine-grained sedimentary rock containing organic matter (kerogen) derived chiefly from the remains of aquatic organisms, waxy spores, and pollen grains, which yield shale oil upon thermal distillation.

Presented herein is an overview of the geology of oil shale, the methods used to evaluate the deposits, the mining and retorting processes that determine resource recovery, and the economics of development. The data cited are from existing publications and generally represent the current and most comprehensive information available.

This paper emphasizes the Green River Formation oil-shale deposits of Colorado, Utah, and Wyoming because of their very large energy resource and potential for development. The Wyoming and Utah oil-shale deposits will be briefly described, but the deposits of the Piceance Creek basin of Colorado will be discussed in more detail. Oil-shale evaluation methods and processing options discussed pertain to the Piceance Creek basin oil-shale deposits, although most of the same techniques and processes could also be applied to other oil-shale deposits.

GEOLOGY

Resource

Oil-shale deposits in the United States are shown in figure 1. Shale-oil resources contained in these deposits are reported in table 1. The

Figure 1. -- Near Here

Table 1. - Near Here

Eocene Green River Formation deposits in Colorado, Utah, and Wyoming contain the largest known resources of shale oil in the world. The Devonian and Mississippian deposits in the eastern and central United States, though widespread, are lean and occur in relatively thin beds. In fact, the estimated shale-oil resources in the eastern and central United States (table 1) are less than half those in the Green River Formation. It is estimated that more than 2 trillion barrels of oil are contained in Green River oil-shale deposits which yield at least 10 gallons of shale oil per ton; of that total, more than 750 billion barrels are contained in high-grade beds that yield at least 25 gallons of shale oil per ton (Donnell, 1964). Eighty percent of this high-grade oil-shale potential, or about 600 billion barrels, is located in the Piceance Creek basin of Colorado; 15 percent, or 113 billion barrels, is in the Uinta basin of Utah; and 5 percent, or 38 billion barrels, is in the Green River basin of Wyoming. The in-place resource in the Piceance Creek basin represents about 60

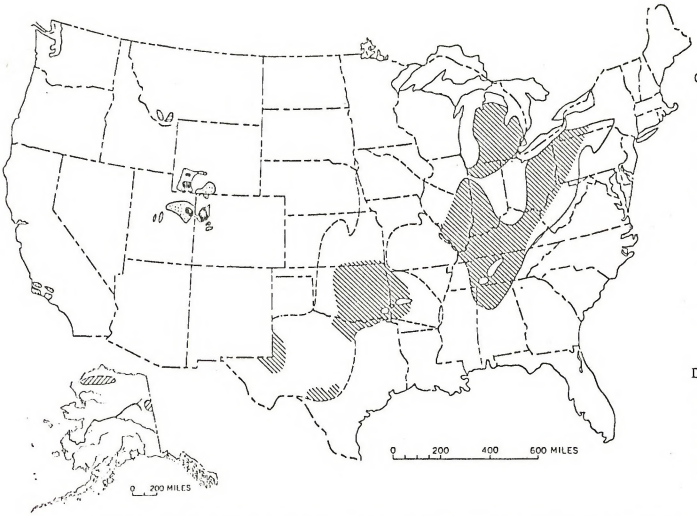
EXPLANATION
Tertiary deposits Green River Formation in Colorado, Utah, and Wyoming; Monterey Formation, California; middle Tertiary deposits in Montana. Black areas are known high-grade deposits
Mesozoic deposits Marine shale in Alaska
Permian deposits Phosphoria Formation, Montana
Devonian and Mississippian deposits (resource estimates included for hachured areas only). Boundary dashed where concealed or where location is uncertain
0 200 400 600 MILES
0 200 MILES

Figure 1. -- Oil-shale deposits in the United States (Duncan and Swanson, 1965).

Table 1. -- Shale-oil resources of the United States, in billions of barrels.
[Data from Duncan and Swanson (1965).]

Location	Shale-oil yield range (gallons/ton)						
	Order of magnitude of total resource*			Known resources, marginal or submarginal recovery			Known recoverable resources
	5-10	10-25	25-100	5-10	10-25	25-100	10-100
Green River Formation: Colorado, Utah, and Wyoming--	4,000	2,800	1,200	2,000	1,400	520	80
Central and eastern United States-	2,000	1,000	NA**	200	200	0	0
Alaskan deposits----------	large***	200	250	small****	small	small	small
Other deposits----------	134,000	22,250	500	NA	small	small	small
TOTAL	140,000	26,250	1,950	2,200	1,600	520	80

*Includes oil shale in known resources, in extensions of known resources, and in undiscovered but anticipated resources.
**Estimate not available.
***Resource considered relatively large when compared with the resource in other locations.
****Resource considered relatively small when compared with the resource in other locations.

times the estimated recoverable reserves of the Prudhoe Bay oil field in Alaska. These basins and their associated oil-shale deposits are shown in figure 2.

Figure 2. Near Here

The extensive black oil shales of the eastern and central United States were deposited during the Devonian and Mississippian Periods and are much older than the western shales. They are marine sediments that contain organic matter relatively poor in hydrogen. An in-place resource of about 200 billion barrels of 10-gallon-per-ton shale has been estimated for a portion of the deposits, although an extensive evaluation program would be required to determine the total resource. Some of the eastern shales have attracted considerable interest, more because of their potential as a source of gas than for their oil potential. The Devonian and Mississipian Antrim Shale underlying large areas of Michigan is receiving attention because of the potential for underground gasification.

Stratigraphy

The lake environments, within which the Green River Formation of Tertiary Eocene age was deposited, occupied an area of about 34,000 square miles in Colorado, Utah, and Wyoming. The Green River, Great Divide, Washakie, and Sand Wash basins of southwest Wyoming, northeast Utah, and

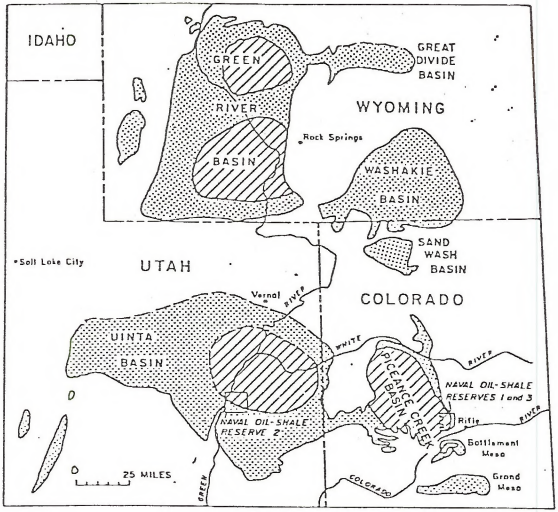

Figure 2. — Oil-shale deposits in the Green River Formation - Colorado, Utah, and Wyoming (Duncan and Swanson, 1965).

northwest Colorado were occupied by Lake Gosiute from 55 to 35 million years ago. The Uinta basin of northeast Utah and the Piceance Creek basin of northwest Colorado were occupied during the same time by Lake Uinta.

The Green River Formation of southwestern Wyoming consists, in the broadest terms, of a body of lacustrine sedimentary rocks interbedded with a thick body of fluviatile sedimentary rocks of the Eocene Wasatch Formation below and Eocene Bridger Formation above. The body of lacustrine rocks that make up the Green River Formation intertongues with these fluviatile rocks as a result of numerous fluctuations of the shoreline of Lake Gosiute. The Green River Formation consists dominantly of oil shale and beds of dolomitic marlstone, with lesser amounts of oolitic limestone and bedded algal deposits, beds of volcanic ash (tuff), and limy sandstone or sandy marlstone.

The oil-shale-rich Green River Formation of the Uinta and Piceance Creek basins is generally exposed along the basin margins. The formation overlies the Eocene Wasatch Formation and, in much of the area, is overlain by the Eocene Uinta Formation (figs. 3 and 4).

Figures 3 and 4. -- Near Here

The oil-shale deposits with potential for development in Utah are located in the eastern part of the Uinta basin; however, the thickest and richest oil shales in the Green River Formation are within the central Piceance Creek basin. Following is a description of the distribution of

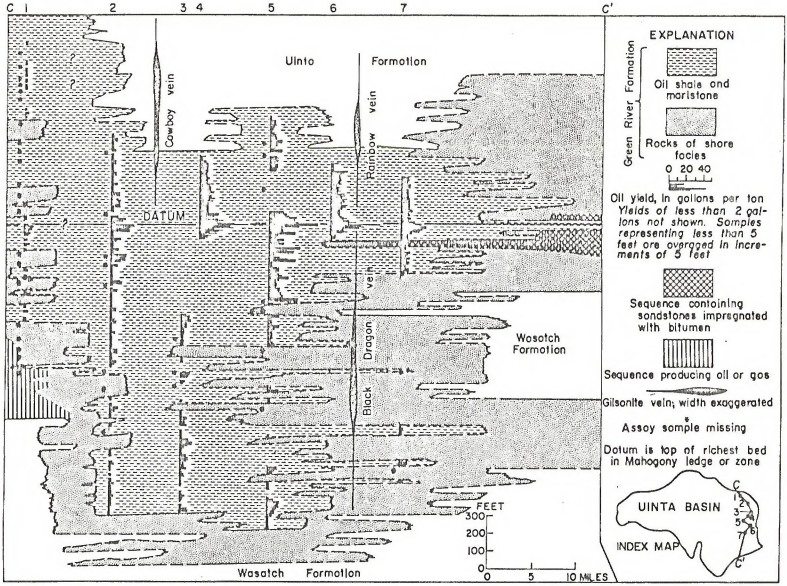

Figure 3. -- Cross section of Green River Formation in Uinta basin, Utah (U.S. Department of the Interior, 1973).

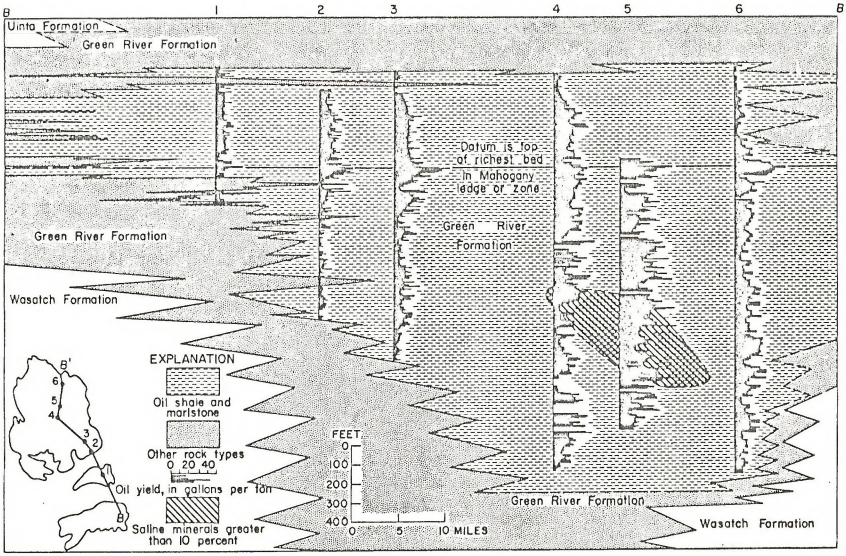

Figure 4. -- Cross section of the Green River Formation in the Piceance Creek basin, Colorado (U.S. Department of the Interior, 1973).

rich oil shale, saline minerals, and associated rocks of the Green River Formation within the Piceance Creek basin.

The Green River Formation of the Piceance Creek basin has been divided into several members, in ascending order: the Douglas Creek Member, Garden Gulch Member, and Parachute Creek Member. The Anvil Points Member is found only in the eastern part of the Piceance Creek basin and is the lateral equivalent of the Douglas Creek, Garden Gulch, and the lower part of the Parachute Creek Members (fig. 5).

Figure 5. -- Near Here

The Douglas Creek Member is resistant to erosion and commonly forms a series of benches in the lower part of the Green River escarpment. The brown-to-buff unit consists of crossbedded and ripple-marked sandstone, algal and ostracodal limestone, and oolitic sandstone and limestone, with minor amounts of gray shale. Maximum thickness of the member is nearly 800 feet in the type section.

The Garden Gulch Member forms gray steep slopes below the precipitous whitish cliffs of the Parachute Creek Member. The unit is characterized by papery to flaky shale with marlstone as the prominent component. Thin beds of sandstone and limestone are locally present. The member locally contains oil shale, but is relatively lean in contrast to the rich shales of

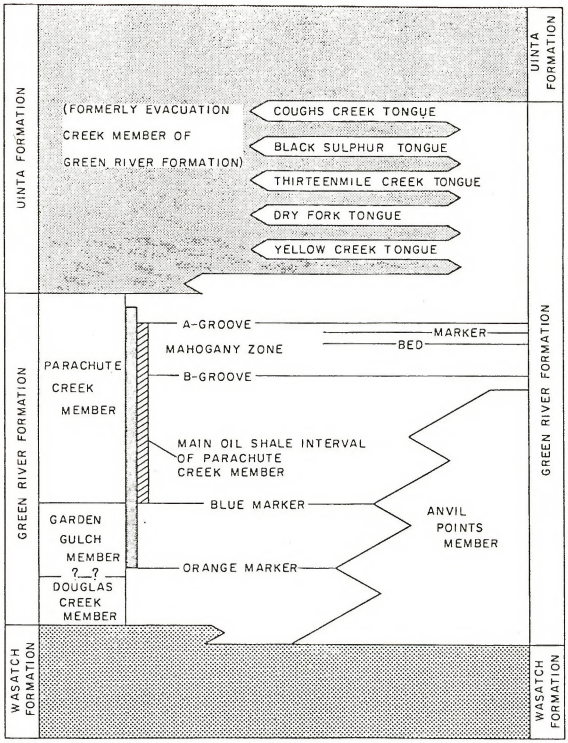

Figure 5. -- Generalized stratigraphic column of Eocene rocks, Piceance Creek basin (Dietz and others, 1977).

Note: The newly named Stewart Gulch Tongue of the Green River Formation is not shown on this figure.

the overlying Parachute Creek Member. A maximum thickness of 1,000 feet of Garden Gulch beds has been identified in wells in the area.

In the center part of the basin, the Garden Gulch and Douglas Creek Members are difficult to differentiate. Two lean oil-shale zones in this Garden Gulch-Douglas Creek unit are correlatable throughout the central part of the basin and are also recognized as distinctive lows on resistivity logs. These are identified as the Blue marker at the top of the Garden Gulch and the Orange marker lower in the Garden Gulch (fig. 5).

The oil-shale-rich Parachute Creek Member forms the upper slopes and cliffs of the basin margin outcrop. The member is composed almost entirely of shale and marlstone which will yield oil when distilled. A thickness of 1,700 feet has been penetrated by wells in the area. The Parachute Creek Member has been divided into the upper and lower oil-shale zones (Donnell, 1961) separated by a thin zone of low-grade oil shale, barren marlstone, sandstone, or siltstone commonly referred to as the B-groove. Alternating rich (R) and lean (L) oil-shale zones (fig. 6) have also been identified

Figure 6. -- Near Here

within the oil-shale interval of the Green River Formation (Cashion and Donnell, 1972).

The lower oil-shale zone attains a thickness of more than 1,000 feet near the center of the basin. A zone of saline minerals (fig. 4) coincides

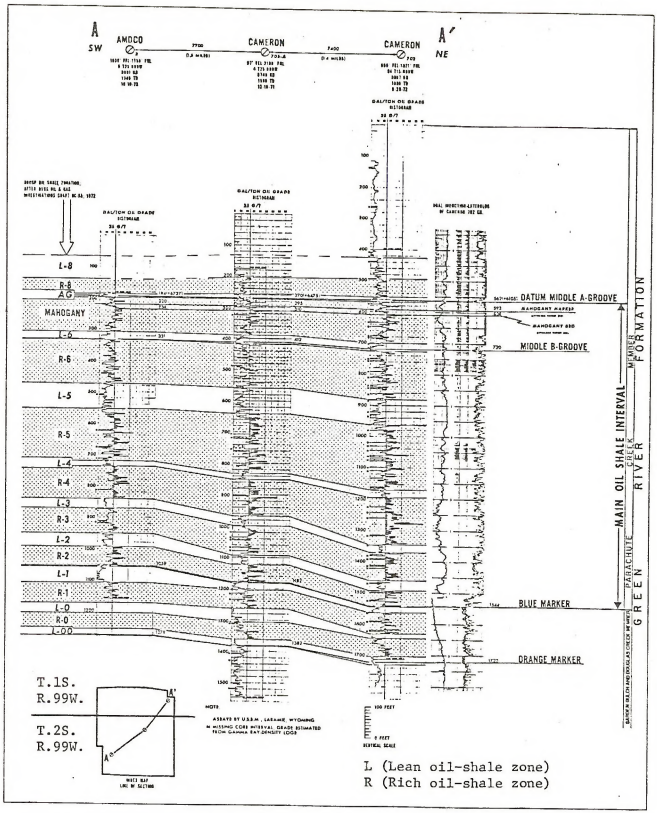

Figure 6. -- Core-hole histogram cross section (Gulf Oil Corporation, and Standard Oil Company - Indiana, 1976).

Note: Middle of the A- and B-grooves refers to the electric log correlation within these zones.

with much of this thick, rich oil shale section. The mineral nahcolite ($NaHCO_3$) occurs as dark crystalline masses, disseminated crystals, and discrete beds. A total resource of about 29 billion tons of nahcolite are present within the Piceance Creek basin (Beard and others, 1974). In an area of approximately 100 square miles, halite (NaCl) is interbedded with nahcolite. Near the center of the basin, a large area of these saline minerals has been dissolved by ground water to form the leached zone. This zone generally extends from the lower part of the upper zone into the lower zone saline section and in places is hundreds of feet thick. The top and base of the leached zone are extremely irregular and are characterized by solution cavities, collapse breccia, open fractures, and porous marlstone. The lower Parachute Creek Member also contains large quantities of dawsonite ($NaAl(OH)_2CO_3$), which occurs as minute crystals disseminated throughout the oil-shale matrix. This mineral has a greater lateral and vertical distribution than nahcolite and has not been dissolved by ground water in the leached zone. A total resource of about 19 billion tons of dawsonite (6.5 billion tons of alumina) is present within the Piceance Creek basin (Beard and others, 1974).

The upper oil-shale zone has a maximum known subsurface thickness of about 620 feet and contains the richest oil shales of the Green River Formation. The lower part of the upper zone consists almost entirely of rich oil shale and is called the Mahogany ledge (zone in the subsurface). The Mahogany ledge or zone (figs. 5 and 6) is thickest and richest in the

north-central part of the basin. Within the Mahogany zone is a persistent 3- to 10-foot unit of exceedingly rich oil shale designated as the Mahogany bed (figs. 5 and 6) which has assayed as high as 79 gallons of oil per ton. An analcitized tuff bed 3-6 inches in thickness is found 3-14 feet above the Mahogany bed and is called the Mahogany marker (figs. 5 and 6). Two very lean oil-shale zones, the A-groove and B-groove (figs. 5 and 6), define the top and bottom, respectively, of the rich Mahogany zone. These units and several other beds in the upper oil-shale zone are remarkably persistent and uniform in character across the basin and are useful for stratigraphic and structural correlation.

The overlying Uinta Formation forms the surface rock in most of the area. Its original maximum thickness is not evident, because the top of the section is the present erosion surface. The lower part of the Uinta Formation in the Piceance Creek basin was formerly termed the Evacuation Creek Member of the Green River Formation (Cashion and Donnell, 1974). The formation consists mainly of light-brown to brown lenticular sandstone and siltstone. Some of the sandstone is thick, massive, and medium- to coarse-grained. Several relatively thin lacustrine light-gray marlstone units tongue northward into the Uinta Formation, six of which have been named and designated as tongues of the Green River Formation (fig. 5). In ascending order, these units are Yellow Creek, Dry Fork, Thirteenmile Creek, Black Sulfur, Coughs Creek, and Stewart Gulch Tongues (Duncan and others, 1974; O'Sullivan, 1975; and Hail, 1977).

Structure

The large depositional and structural Piceance Creek and Uinta basins are separated by the Douglas Creek arch, a broad gentle upwarp south of Rangely, Colorado. Both basins are asymmetric with steeply dipping limbs on the north and very gently dipping limbs on the south. Dips are toward the basin centers and range from 1^{o} to about 35^{o}. Several subparallel west-northwest-trending folds interrupt the predominant structural trend. Faulting is minor in the area and neither the density nor displacement of faults is of significant magnitude. The faults are vertical, or nearly so, with displacements less than 200 feet. Most of the northwest-trending faults bound graben structures.

A well-defined system of northwest- and northeast-trending near-vertical joint sets are present in the Green River strata. A partial adjustment of many small streams to this joint system has resulted in a trellis-like drainage pattern. The joint system developed after deposition of the Uinta Formation and during the downwarping of the basins. Gilsonite veins (a naturally occurring solid hydrocarbon), as much as 18 feet wide, occur along some of the northwest-trending joints in the Uinta basin.

EXPLORATION

An oil-shale geologic exploration program is simplified because the location and distribution of oil-shale deposits in the Green River Formation have been previously documented. Exploration efforts will emphasize defining the known deposits and determining the value of an oil-shale property. This area of exploration is much smaller than many other energy resources such as coal or crude oil. The exploration program is designed to provide the geologic, engineering, environmental, and hydrologic data necessary for an economic evaluation and the selection of a mining and retorting system to optimize development of the oil-shale property. The investigation begins with a review of available geologic literature, aerial photographs, maps, and core-hole data. This preliminary information determines the extent and detail required for further geophysical and geological investigations of the oil-shale deposit.

The exploration plan incorporates both surface and subsurface investigations. Surface investigations include aerial photography, and photogeologic and surface geologic mapping. Subsurface investigations consist of the interpretation of data from core-hole lithologic logs, geophysical logs, and core samples to obtain sufficient oil-shale resource, overburden, and subsurface structural information.

Aerial photography

Aerial photography provides a base for detailed photogeologic, environmental, mining, and surface facilities investigations. Color, color-infrared, and black-and-white stereographic aerial photographs at a scale of 1 in. to 1,000 ft. to 1 in. to 3,000 ft. have been used. Color and color-infrared photography are especially useful for vegetation mapping and photogeologic interpretations. Prior to photographic overflights, ground control stations are located and appropriately marked. These control stations are readily identifiable on photos and are necessary for construction of controlled mosaics and base maps.

Geologic mapping

The particular emphasis of photogeologic mapping and interpretations is the definition of major faults, joints, and other lineaments. Location, strike, dip, and spacing of joints, fractures, and faults is determined and recorded on an appropriate base map. A thorough knowledge of these features is useful in predicting slope stability, ground water movement, mine stability (surface and underground), and facility site locations. Photogeologic interpretations are field checked during surface geologic mapping to further refine the structural interpretation of the area being evaluated.

The primary purpose of the geologic mapping program is to define the areal distribution, thickness, continuity, and lithology of the surface geologic units in the area. Such descriptions and measurements will primarily include the Parachute Creek Member of the Green River Formation, the Uinta Formation, and Quaternary materials. Evaluation of Quaternary materials is important in the selection and planning of surface facilities for development of the oil-shale deposit. Geologic sections are measured in areas of good exposure to determine lithology and to correlate mapping horizons between sections and future core holes. Surveying techniques, such as plane-table mapping, are used to accurately locate mappable beds, fold axes, faults, and other surface structural features. Joint orientation data are collected and used to define joint sets and joint systems. A rose diagram or equal area net assists in the portrayal and analysis of joint data.

Core-hole program

A detailed and well-planned core-hole program is the most valuable tool for an economic evaluation of an oil-shale deposit. An adequate number of core holes must be planned to obtain sufficient oil-shale resource, overburden, and subsurface structural data. A minimum of one core hole per section (640 acres) is necessary with additional "in-fill" core holes to provide supplemental data where necessary for detailed economic evaluation and delineation of subsurface structural features. These additional core

holes may result in a total of as many as three core holes per section for a typical oil-shale property. It is especially important to accurately determine fault displacements, fault zone hydrologic conditions, and the presence of highly fractured zones which may affect the minability of oil-shale intervals.

Core holes usually are drilled with air-mist rather than mud to minimize formation damage and leaching of saline minerals, and to provide optimum hydrologic testing and drill-hole logging conditions. Core is typically 2 1/2 in. to 3 1/2 in. in diameter and all efforts are made to obtain maximum core recovery. During the initial core-hole program, continuous coring usually begins at bedrock with total depth near the Orange marker (figs. 5 and 6), to obtain data on overburden characteristics as well as the entire oil-shale sequence. Later "in-fill" drilling can be restricted to specific oil-shale intervals of development interest.

The core-hole program includes lithologic logs, geophysical logs, and assays of core samples for shale oil, nahcolite, and extractable alumina content. Core samples are also used for rock mechanics testing to provide information for structural design of the oil-shale mine. Core holes are used for subsequent hydrologic testing to define the ground-water aquifer system.

Qualified geologic personnel describe, log, and photograph the lithologic and structural characteristics of the core or drill cuttings.

A well-constructed lithologic log presents a description of the rock type by depth as well as data on structure dip, joints, fractures, partings, and rock quality designations (RQD). RQD is calculated by summing the pieces of core that are of a minimum length (example, 0.35 feet) or longer and dividing by any constant length (example, 10 feet). This percentage relationship represents both fractures and partings contained within the rock strata and therefore the rock quality. Ground-water depths, water production (or drilling fluid loss), and water quality are noted during drilling. It is also important to note and record any methane (CH_4) or hydrogen sulfide (H_2S) gas encountered.

Geophysical logs are run in the core holes as soon as possible after drilling to obtain additional information for lithologic correlation, shale grade, rock type, porosity, and water production. Typical geophysical logs used for oil-shale evaluation are density, gamma ray, caliper, resistivity, spontaneous-potential (SP), sonic, neutron, temperature, and spinner logs. The density log is important for oil-shale evaluation because the density of oil shale is inversely related to grade. The gamma ray log can often identify tuff beds and is used in lithologic correlations, as is the caliper log. Because of the electrically resistive properties of kerogen, high-grade oil shales appear as resistivity highs on electrical logs. The A- and B-grooves, Orange marker, and Blue marker (figs. 5 and 6) are identified as resistivity lows. The SP log provides data for lithologic correlation, and for porosity and permeability evaluation. Sonic logs can be used to estimate oil-shale grade because travel time increases with

kerogen content; they are also valuable for fracture and rock mechanics studies. The neutron log assists in porosity and lithology determinations and can be used to estimate oil-shale yield. The temperature log is useful for detecting water- and gas-producing zones and the spinner log assists in determining ground-water zones and flow rates.

Core assay data

Oil yield assays are usually run on 1- to 2-foot core intervals, but have also been run on 5-foot increments. The modified Fischer assay method (Goodfellow and Atwood, 1974) provides oil yield data for the oil-shale resource evaluations. Each sample is retorted in the laboratory to determine oil and water contents in gallons per ton and residue (spent shale) weight in pounds per ton. "Gas plus loss" is also calculated for each sample. The stainless steel, gas-tight retort (figs. 7 and 8) is

Figures 7 and 8. -- Near Here

heated to 932°F to decompose the kerogen and produce shale oil. The standard deviation reported for oil yield from samples averages about 0.5 percent on a volume basis (Goodfellow and Atwood, 1974).

Where the minerals nahcolite and dawsonite have been deposited in the oil-shale formation, nahcolite and extractable alumina analyses, as part of the core-hole program, are important for an economic evaluation. Nahcolite

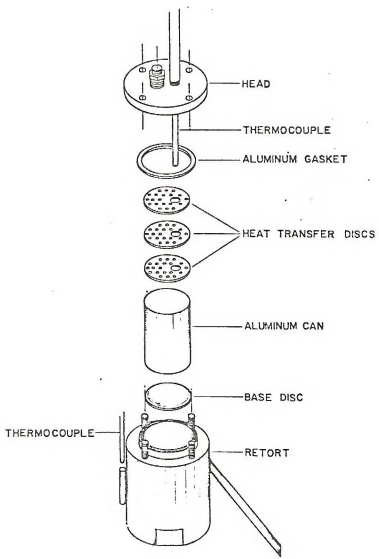

Figure 7 -- Fischer assay retort assembly (Goodfellow and Atwood, 1974).

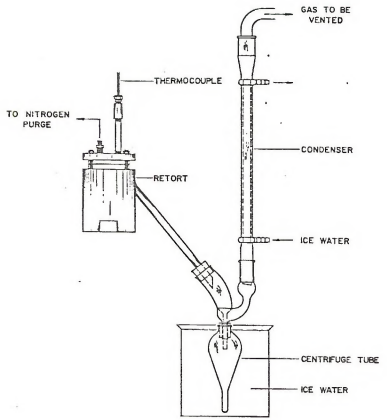

Figure 8 -- Fischer assay product collection assembly (Goodfellow and Atwood, 1974).

content (weight percent) is determined by water leaching of nahcolite-bearing shale. Nahcolite will be dissolved during core drilling and visual examination of the remaining vugs in the core may be necessary for estimation of the nahcolite content. Alumina content (weight percent Al_2O_3) is determined by either the acid-extraction or alkaline-extraction procedure. The acid leach method (Smith and Young, 1975) uses hydrochloric acid on raw oil shale and measures soluble alumina by atomic absorption. The base-extraction method (Haas and Atwood, 1975) uses a sodium hydroxide solution on spent shale from the Fischer assay analysis and measurement of soluble alumina by atomic absorption. Alumina content is then corrected back to a raw shale basis using the Fischer assay weight loss.

Rock mechanics

The purpose of a rock mechanics program is to establish basic rock mechanics parameters needed for oil-shale mine design work. The geotechnical analysis consists of laboratory tests on cores obtained from the drilling program. Rock mechanics properties may vary widely between oil-shale deposits, owing to differences in oil-shale mineralogy. Therefore, specific geotechnical analyses are performed for each oil-shale deposit evaluated. Rock properties determined from core testing include uniaxial compressive strength, modulus of elasticity, tensile strength, angle of internal friction, cohesion, rock density, shear strength, modulus of rupture, and Poisson's

Ratio. The uniaxial compressive strength of oil shale has been shown to decrease with increase in oil content (fig. 9) as do the modulus of

Figure 9. -- Near Here

elasticity and angle of internal friction. The Brazilian Tensile Test shows some correlation with the uniaxial strength tests and also provides an indirect measure of tensile strength. Specific gravity determinations are not made in routine assays, but the relationship between decreasing oil-shale density or specific gravity with increasing oil content is well established (fig. 10).

Figure 10. -- Near Here

Table 2 shows the specific gravity, weight of oil shale, volume of oil shale, and oil yield per unit volume for oil shale yielding from 0 to 100 gallons of oil per ton by assay. These values are based on oil

Table 2. -- Near Here

yields from the Mahogany zone near Rifle, Colorado, and are considered representative of oil shales in the Piceance Creek basin. However, this relationship varies in different parts of the basin and in oil shales located above or below the Mahogany zone.

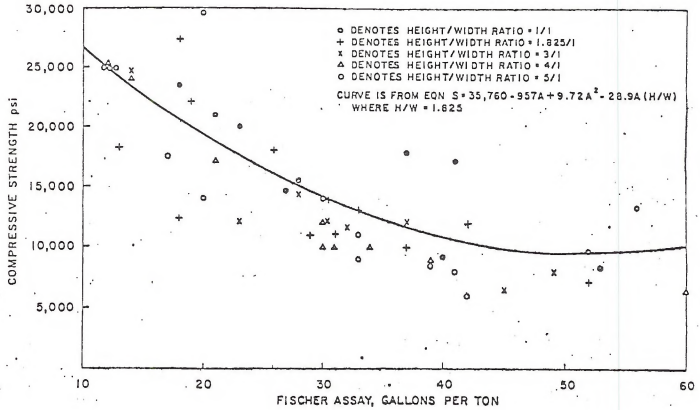

Figure 9 -- Relation between compressive strength and oil-shale grade (Agapito, 1972).

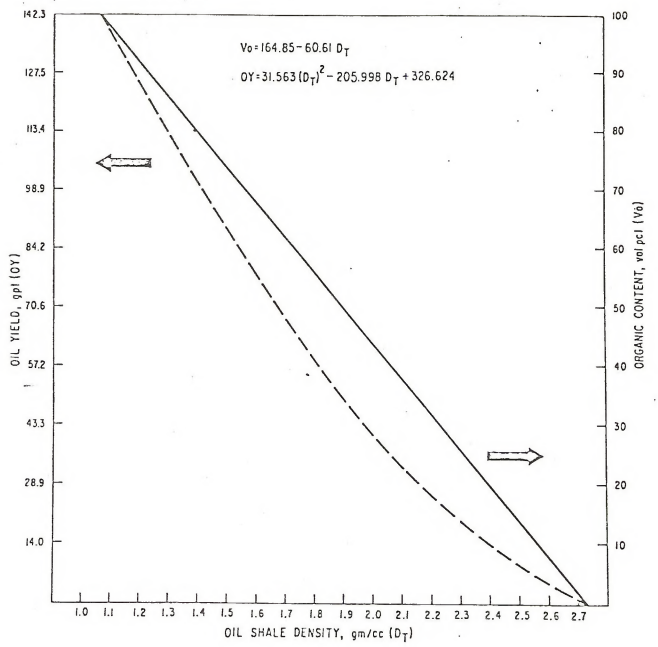

Figure 10 — Relationship of oil-shale density to oil yield and organic content (Smith, 1976).

Table 2. -- Volume-weight-oil yield relationships for oil shale (Stanfield and others, 1957).

Oil yield by assay (gal./ton)	Specific gravity of oil shale, 60°/60° F.	Weight of oil shale per unit volume, lb./cu. ft.	Volume of oil shale per unit weight, cu. ft./ton	Oil yield per unit volume gal./cu. ft.
0	2.714	169.08	11.829	0
1	2.687	167.40	11.947	0.084
2	2.660	165.72	12.069	.166
3	2.634	164.10	12.188	.246
4	2.610	162.60	12.300	.325
5	2.586	161.11	12.414	.403
6	2.564	159.74	12.520	.479
7	2.542	158.37	12.629	.554
8	2.520	157.00	12.739	.628
9	2.499	155.69	12.846	.701
10	2.478	154.38	12.955	.772
11	2.458	153.13	13.061	.842
12	2.439	151.95	13.162	.912
13	2.420	150.77	13.265	.980
14	2.400	149.52	13.376	1.047
15	2.383	148.46	13.472	1.113
16	2.364	147.28	13.580	1.178
17	2.347	146.22	13.678	1.243
18	2.330	145.16	13.778	1.306
19	2.313	144.10	13.879	1.369
20	2.297	143.10	13.976	1.431
21	2.280	142.04	14.081	1.491
22	2.264	141.05	14.179	1.552
23	2.248	140.05	14.281	1.611
24	2.233	139.12	14.376	1.669
25	2.218	138.18	14.474	1.727
26	2.203	137.25	14.572	1.784
27	2.188	136.31	14.672	1.840
28	2.173	135.38	14.773	1.895
29	2.159	134.51	14.869	1.950
30	2.145	133.63	14.967	2.004
31	2.130	132.70	15.072	2.057
32	2.117	131.89	15.164	2.110
33	2.103	131.02	15.265	2.162
34	2.089	130.14	15.368	2.212
35	2.076	129.33	15.464	2.263
36	2.063	128.52	15.562	2.313
37	2.050	127.72	15.659	2.363
38	2.037	126.91	15.759	2.411
39	2.024	126.10	15.860	2.459
40	2.012	125.35	15.955	2.507
41	1.999	124.54	16.059	2.553
42	1.986	123.73	16.164	2.598
43	1.974	122.98	16.263	2.644
44	1.961	122.17	16.371	2.688

Table 2 -- Volume-weight-oil yield relationships for oil shale (Stanfield and others, 1957) -- continued

Oil yield by assay (gal./ton)	Specific gravity of oil shale, 60°/60° F.	Weight of oil shale per unit volume, lb./cu. ft.	Volume of oil shale per unit weight, cu. ft./ton	Oil yield per unit volume gal./cu. ft.
45	1.949	121.42	16.472	2.732
46	1.937	120.68	16.573	2.776
47	1.925	119.93	16.676	2.818
48	1.914	119.24	16.773	2.862
49	1.902	118.49	16.879	2.903
50	1.890	117.75	16.985	2.944
51	1.879	117.06	17.085	2.985
52	1.867	116.31	17.195	3.024
53	1.856	115.63	17.297	3.064
54	1.845	114.94	17.400	3.103
55	1.834	114.26	17.504	3.142
56	1.823	113.57	17.610	3.180
57	1.812	112.89	17.716	3.217
58	1.801	112.20	17.825	3.254
59	1.790	111.52	17.934	3.290
60	1.779	110.83	18.046	3.325
61	1.769	110.21	18.147	3.361
62	1.758	109.52	18.262	3.395
63	1.748	108.90	18.365	3.430
64	1.737	108.22	18.481	3.463
65	1.727	107.59	18.589	3.497
66	1.717	106.97	18.697	3.530
67	1.707	106.35	18.806	3.563
68	1.696	105.66	18.929	3.592
69	1.686	105.04	19.040	3.624
70	1.676	104.41	19.155	3.654
71	1.666	103.79	19,270	3.684
72	1.656	103.17	19.385	3.714
73	1.647	102.61	19.491	3.745
74	1.637	101.99	19.610	3.774
75	1.627	101.36	19.732	3.801
76	1.618	100.80	19.841	3.830
77	1.608	100.18	19.964	3.857
78	1.598	99.56	20.088	3.883
79	1.589	98.99	20.204	3.910
80	1.579	98.37	20.331	3.935
81	1.570	97.81	20.448	3.961
82	1.561	97.25	20.566	3.987
83	1.551	96.63	20.698	4.010
84	1.542	96.07	20.818	4.035
85	1.533	95.51	20.940	4.059
86	1.524	94.95	21.064	4.083
87	1.515	94.38	21.191	4.106
88	1.506	93.82	21.317	4.128
89	1.497	93.26	21.445	4.150
90	1.488	92.70	21.575	4.171
95	1.444	89.96	22.232	4.273
100	1.401	87.28	22.915	4.364

EVALUATION

The stratigraphic, structural, and resource information gathered from various phases of the oil-shale exploration program is used in the evaluation of the oil-shale deposit. These data are interpreted to determine the areal and vertical extent of the oil-shale deposit, and the nature and thickness of the overburden. In addition, the quantity and grade of oil shale and distribution and content of any saline minerals are determined. This information is compiled on detailed geologic maps, cross sections, and contour maps.

Detailed geology

Data from the aerial photography, geological mapping, and core-hole programs are used to prepare a detailed report that includes a geologic map and cross sections. The geologic map shows the extent of the various rock units (including the marker beds), fault and joint systems with displacement or movement along them, and structure contours. The structure contours are based on plane-table or other survey data, the topographic base, and the core-hole information. Middle of the A-groove (figs. 5 and 6) is commonly used as a datum for the structure contours.

Geologic cross sections are drawn from the surface and core-hole lithologic correlations, geophysical logs, and core-hole assay data. These

cross sections delineate the lithologies (Uinta Formation through the Parachute Creek, Douglas Creek and Garden Gulch Members of the Green River Formation), units (A-groove, B-groove, Mahogany zone, and Mahogany bed), markers (Orange, Blue, and Mahogany), and oil-shale zones (R and L). The top and base of the leached zone, if present, are also identified. Oil-shale grade and sodium mineral analyses can be graphically presented with histograms (fig. 6) at the same vertical scale as the lithologic cross section for each core hole. A vertical scale of from 1 in. to 20 ft. to 1 in. to 100 ft., with a horizontal scale of 1 in. to 40 gallons of oil per ton, is commonly used. Mining intervals identified in the evaluation process can also be delineated on the cross sections.

Resource

The core assay data are used to calculate oil yield and thickness values for the oil-shale deposit. To determine the average assay value of the total core interval thickness, the values of individual samples are weight averaged according to the thickness of the strata represented. For an interval where core is missing, oil-shale grade can be estimated from the formation density log of the hole. These data are compiled and calculations made to determine the maximum thickness of zones that will yield an average of 15, 25, or 30 gallons of oil per ton in a continuous sequence of 15 feet or more. The U.S. Geological Survey has developed a computer program to simplify these calculations. These minimum thicknesses and

average oil-shale grades correspond approximately to the minimum thickness and grade of oil shale exploited on a sustained basis in other parts of the world (Donnell, 1961). Shale oil is not now being produced commercially in the U. S.; therefore, it is not possible to predict with assurance what average grade or minimum mineable thickness will prove economical.

There are a number of methods which can be used to determine resource values from several individual core holes. The choice of a specific method is determined by the spacing of core holes, lateral grade variation in the deposit, and the geologic structure. Exploratory drilling usually results in irregularly spaced core holes. The area of influence or polygon method for resource calculations is usually used in these instances, but because of small lateral changes in oil-shale grade in most deposits a contouring method can be used.

In the contouring method, thickness data are used to compile a series of isopach maps for each zone or level from which the average thickness of each grade of oil shale is determined for the deposit. The volume of oil shale is then computed and converted to tons using the specific gravity (fig. 10) of the shale at each grade. Oil-shale tonnage at a specific grade is then converted to total in-place barrels (42 gallons/bbl) of oil and this is tabulated to provide a detailed appraisal of both the distribution of continuous stratigraphic sequences and the oil yield of these zones.

Core assay data are also used to calculate the average grade and in-place resources of individual zones or mine levels. Histograms are helpful in the visual portrayal of these core assay data. Isograd, isopach, and isoresource maps are drawn for each zone or mine level. This information provides the details for mining-zone selection and an estimate of the economics of commercial extraction. The recoverable shale oil from these zones will always be less than the in-place resources because of losses in mining and processing, possible adverse structural conditions, hydrologic problems, and cutoff limits of grade, depth, and distance from the outcrop. (Resource recovery is discussed later in this article.)

In-place shale-oil resources can also be estimated using the procedure outlined by Stanfield and others (1957). Figure 11 presents a graphic

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Figure 11. -- Near Here

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method for converting average grade (gal./ton) of oil shale in a zone or mine level to a barrel per acre-foot of shale-oil resource. The thickness of the zone or mine level then determines the total in-place resource for the oil-shale deposit. This oil-shale grade-volume relationship varies slightly between deposits.

Beard and others (1974) described a procedure for determining the total resources of nahcolite and dawsonite within an oil-shale deposit. The basic information required is: (1) weight percent nahcolite and dawsonite for each assay sample, (2) oil yield from assay data,

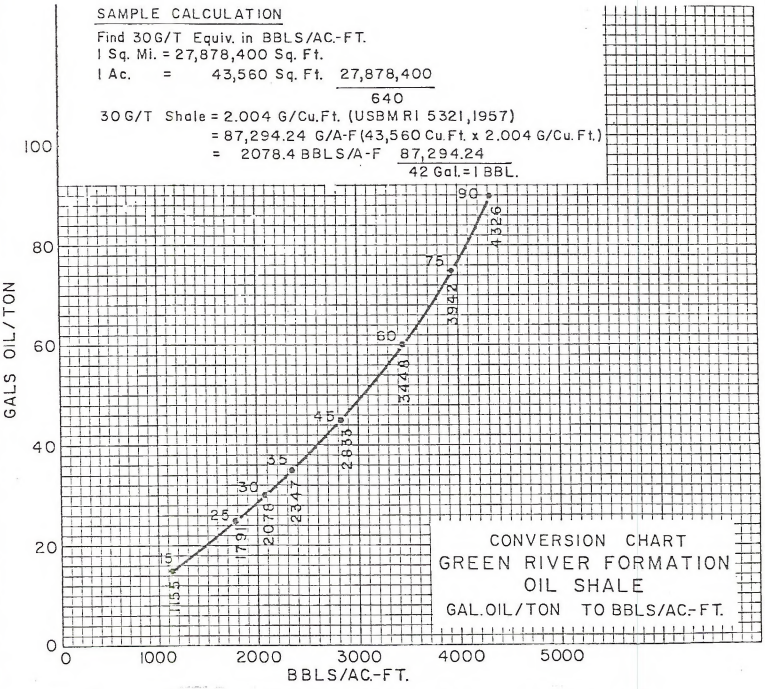


Figure 11. -- Conversion chart, gal. oil/ton to bbls./ac. ft., Green River Formation oil shale (Murray, 1974).

(3) sample depth and thickness, and (4) depths to the top and bottom of the nahcolite and dawsonite-bearing intervals. The procedure compensates for the exclusion of nahcolite and the incorporation of dawsonite in the oil shale as well as variations in shale specific gravity. Isopach, isograd, and isoresource maps are used to determine the total resources of nahcolite and dawsonite within the deposit. Minimum grades of 5 weight percent nahcolite and 1 weight percent extractable alumina have been used in some evaluations.

DEVELOPMENT METHODS

The mining and retorting systems used to develop an oil-shale deposit determine the ultimate resource recovery. Resource recovery is the amount of kerogen actually recovered expressed as a percentage of the total amount of kerogen present based on the Fischer assay of the shale. For the systems described below, expected resource recovery is calculated by multiplying the theoretical mining or areal extraction in the oil-shale interval by the percent kerogen recovery (retort efficiency) resulting from the retorting operation.

Mining

Surface retorting of oil shale requires mining of the shale deposit. Oil shale can be mined by either surface or underground mining techniques. The mining method is determined by overburden depth, oil-shale thickness and grade, deposit size, ground water, other site-specific geological characteristics, and costs. The selection of a specific mining technique for an oil-shale deposit results in various recovery percentages.

Surface or open-pit mining (fig. 12) is an economically attractive

Figure 12. -- Near Here

method for large deposits of low- to medium-grade ore, because it permits

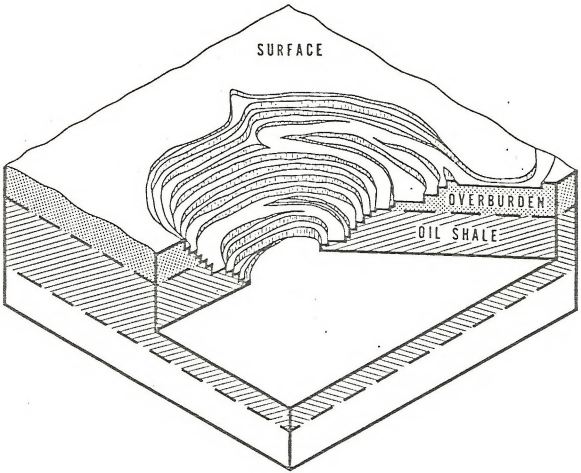


Figure 12. -- Schematic open-pit development (Gulf Oil Corporation and Standard Oil Company - Indiana, 1976).

high recovery of the resource and provides room for large and efficient mining equipment. Open-pit oil-shale mining would be comparable to the open-pit mining of iron and copper deposits. The open pit increases in size and depth as material is removed from the pit floor and from pit wall benches. While the pit is being developed, waste material must be removed and transported to an out-of-pit disposal area. When the ultimate operating depth (as much as 2,000 ft.) is reached, with mining complete on one pit wall and adequate bench and pit floor space is developed to safely operate equipment, the waste material can be backfilled into the mined-out areas. The waste-to-shale-oil ratio is a crucial consideration in oil-shale surface mining. As the minimum or cutoff grade of oil shale increases, the amount of waste material and the waste-to-shale-oil ratio increases. The economical pit depth is also influenced by haulage costs, slope stability, overburden, and equipment limits. At some point, it is more economical to begin an underground mining operation than it is to remove the overburden for an open-pit mine. It is possible to recover almost 100 percent of the oil in a particular zone by open-pit mining; but this recovery is reduced by the oil-shale resource remaining behind the sloping pit walls and beneath the economic pit floor. For example, open-pit mining would achieve about 65 percent recovery of the total resource within Federal oil shale lease tract C-a (Gulf Oil Corporation and Standard Oil Company-Indiana, 1976). The relationship of mining cost and stripping ratio to cutoff grade for a specific tract in the Piceance Creek basin is illustrated in figure 13.

Figure 13. -- Near Here

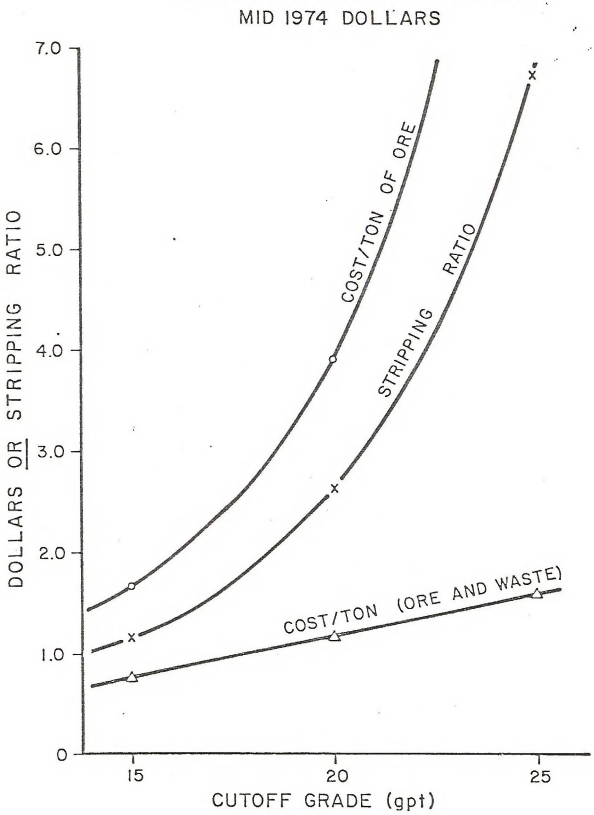


Figure 13. -- Unit cost and stripping ratio versus cutoff grade, open-pit mine (Sun Company, Suntech, Inc., 1976).

The cost per ton of ore at a cutoff grade of 25 gallons per ton falls outside the graph in figure 13, but is $12.16 (1974 dollars).

Underground room-and-pillar mining is well suited to thick, rich, and extensive oil-shale deposits with overburden depths exceeding the economic stripping ratio. In room-and-pillar mining, a portion of the oil-shale deposit is removed, forming large rooms, and pillars are left in place to support the roof (fig. 14). A multiple-level room-and-pillar mine could be developed in an oil-shale deposit with several rich oil-shale zones separated by stable sill pillars (fig. 15). The relative sizes of the

Figure 14. -- Near Here
Figure 15. -- Near Here

pillars and rooms are determined by the physical properties of the oil shale, overburden thickness, and height of the mine roof. For example, Colony Development Operation (U.S. Department of Interior, 1977) has proposed a 61,000 ton/day underground room-and-pillar oil-shale mine in a 60-foot-thick section of the Mahogany zone. The oil-shale interval averages about 35 gallons/ton. Development plans propose 60-foot-wide rooms and 60-foot-square pillars with mining conducted in two 30-foot-high benches or stages. With this method, about 60 percent of the mine interval can be extracted for processing, and the remainder left in place as pillars. Resource recovery of the entire oil-shale sequence would represent an even smaller percentage. Even in a multiple-level room-and-pillar mine, oil shale remains in the sill between mining levels and in the larger pillars

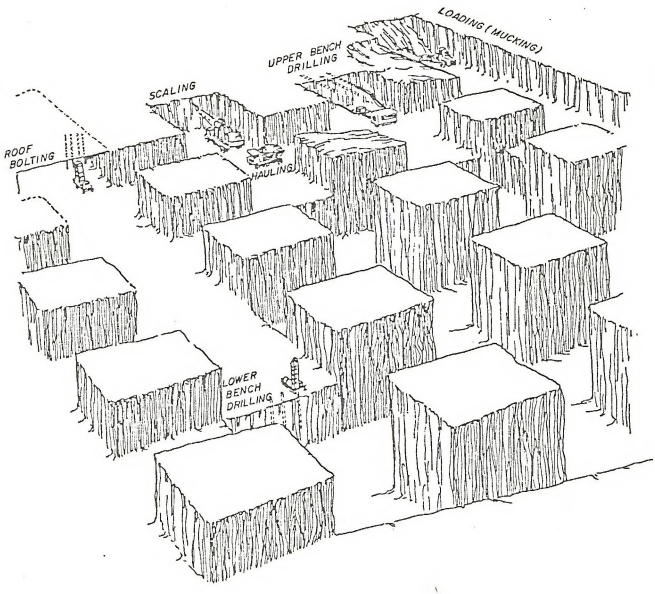


Figure 14. -- Room-and-pillar mine (U.S. Department of Interior, 1977).

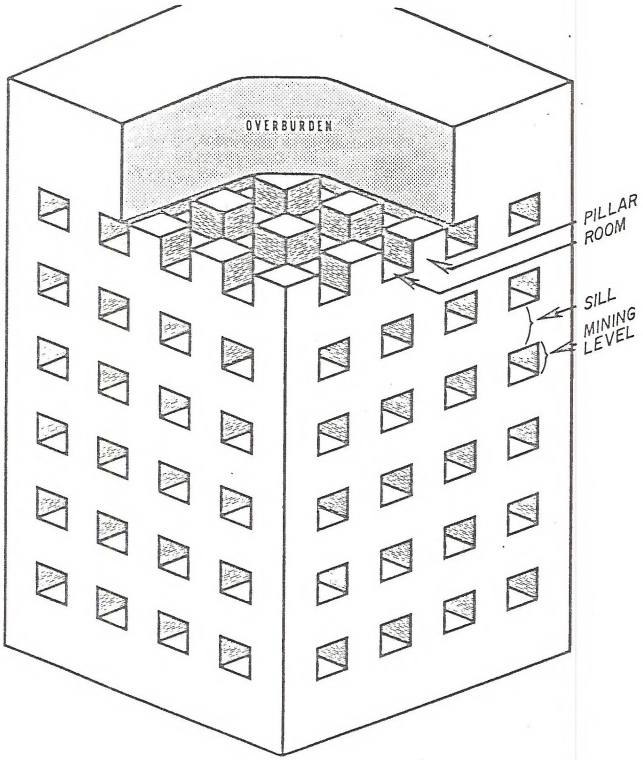


Figure 15. -- Multiple-level room-and-pillar mining (Gulf Oil Corporation and Standard Oil Company - Indiana, 1976).

and smaller rooms required for the deeper levels. For example, multiple-level room-and-pillar mining would achieve only about 14 percent of the total resource within Federal oil shale lease tract C-a (Gulf Oil Corporation and Standard Oil Company-Indiana, 1976).

Alternatives to oil-shale room-and-pillar mining which have been studied (Cameron Engineers, 1976), but not evaluated in the field, include chamber-and-pillar mining, sublevel stoping, and block caving.

Chamber-and-pillar mining (fig. 16) is a modification of room-and-

Figure 16. -- Near Here

pillar mining. This multi-level method was especially designed for underground disposal of processed shale and can vary in design according to geologic and economic conditions. Processed-shale backfilling is started when a chamber is completely mined out. Resource recovery within a mining horizon is estimated to be from 52 to 64 percent, and from 31 to 39 percent within an entire oil shale sequence (Cameron Engineers, 1976).

The sublevel stoping method (fig. 17) can be designed for either of

Figure 17. -- Near Here

the following two systems:

(1) Allow for full subsidence of the overburden, in which the mining is done on the retreat; or

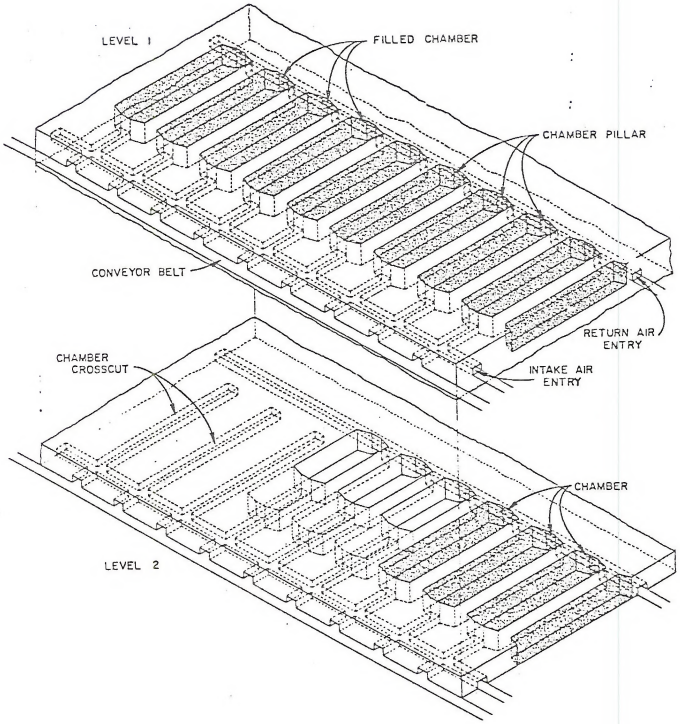


Figure 16. -- Isometric view, chamber-and-pillar mining (Cameron Engineers, 1976).

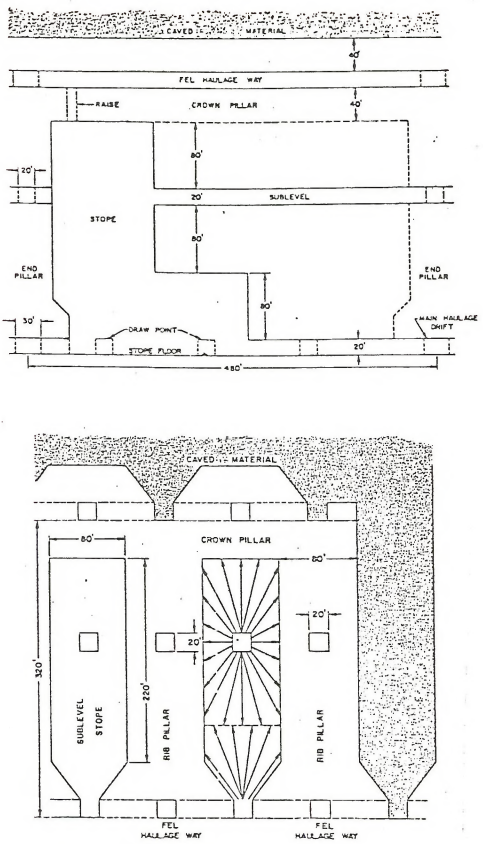


Figure 17. -- Cross section of a sublevel stope (Cameron Engineers, 1976).

(2) Incorporate processed-shale backfilling for minimum subsidence, in which the mining is done on the advance.

In the full-subsidence system, the pillars are drilled and sequentially blasted into the stope after it is completed; the overburden is allowed to cave and the rock is removed from the blasted pillars. In the minimum-subsidence system, the stopes are backfilled with processed shale from a previously mined upper level or from a separately developed fill level. Both systems can be designed for multi-level development, if conditions permit. Resource recovery within an entire oil-shale sequence is estimated to be 82 percent for the first system and 52 percent for the second system (Cameron Engineers, 1976).

The block caving method (fig. 18) is designed for mining thick oil-

Figure 18. -- Near Here

shale sequences and is retreat in character. A mining level is driven under the oil-shale zone and the roof is blasted to initiate caving. The broken shale developed by subsidence is removed from the mine and retorted on the surface. Processed shale from the surface retorts is dumped into the surface cavity formed and the cycle is repeated until the shale deposit is depleted. Resource recovery within an entire oil-shale sequence by this method is estimated to be from 90 to 95 percent (Cameron Engineers, 1976).

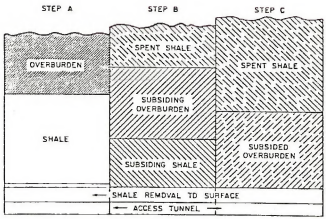


Figure 18. -- Sequence of steps for massive block caving (from Allsman, 1968).

Table 3 presents capital and production costs for four underground mining systems. The unit production costs range from $1.34 to $1.46 per

Table 3. -- Near Here

ton for an average oil-shale grade of 30 gpt. These same mining costs will range from $2.25 to $2.45 per ton if an average oil-shale grade of 25 gpt is assumed (Cameron Engineers, 1976).

Description	Candidate Mining System			
	Chamber and Pillar	Sublevel Stoping With Spent Shale Backfill	Sublevel Stoping With Full Subsidence	Block Caving Using LHD's
Capital Investment				
Equipment	$ 40,114,000	$ 46,745,000	$ 55,349,000	$ 41,730,000
Site development and engineering	14,000,000	14,000,000	14,000,000	14,000,000
Shafts and facilities	26,690,000	29,800,000	25,400,000	28,210,000
Exploration and environmental	6,000,000	6,000,000	6,000,000	6,000,000
Preproduction mining development	4,074,000	12,948,000	22,903,000	25,335,000
Interest and taxes during development	7,600,000	13,623,000	20,689,000	18,643,000
Working capital	5,300,000	5,513,000	5,174,000	4,855,000
Total	$103,778,000	$128,629,000	$149,513,000	$138,773,000
Annual and (unit) Production Cost				
Labor and supervision	$ 13,800,000 (0.46)	$ 16,050,000 (0.53)	$ 14,244,000 (0.47)	$ 13,653,000 (0.46)
Operating supplies	6,215,000 (0.20)	5,018,000 (0.17)	4,682,000 (0.16)	4,258,000 (0.14)
Power	3,131,000 (0.10)	3,383,000 (0.11)	3,334,000 (0.11)	3,055,000 (0.10)
Environmental and reclamation	1,430,000 (0.05)	1,430,000 (0.05)	1,430,000 (0.05)	1,430,000 (0.05)
Indirect costs	814,000 (0.03)	841,000 (0.03)	760,000 (0.02)	719,000 (0.02)
Insurance and taxes	1,103,000 (0.04)	1,323,000 (0.04)	1,566,000 (0.05)	1,181,000 (0.04)
Depreciation	5,399,000 (0.18)	5,903,000 (0.19)	7,084,000 (0.23)	5,906,000 (0.19)
Interest cost	5,140,000 (0.17)	6,302,000 (0.21)	7,280,000 (0.24)	6,731,000 (0.22)
Royalty	3,621,000 (0.12)	3,621,000 (0.12)	3,621,000 (0.12)	3,621,000 (0.12)
Total	$ 40,653,000 (1.35)	$ 43,871,000 (1.45)	$ 44,001,000 (1.46)	$ 40,554,000 (1.34)

Table 3. -- Summary of underground mining costs at an average grade of 30 gpt, first quarter 1975 dollars (Cameron Engineers, 1976).

Surface retorting

Oil shale must be heated to about 900°F to decompose the contained kerogen and produce crude shale oil, gas, and carbonaceous residue. Retorting techniques include surface retorting, true in-situ retorting, and modified in-situ retorting. Ultimate resource recovery is determined by the selection of a specific retorting technique for the oil-shale deposit. While it would be desirable to compare the cost of shale-oil production by various retorting processes, published economic data on each process are unavailable.

Most surface retorts produce a heavy, viscous shale oil with high pour points, moderate sulfur values, and high nitrogen content. These properties make the transportation of crude shale oil very difficult. Therefore, surface retorting complexes will require some upgrading or partial refining facilities to lower the pour point and reduce viscosity of the crude shale oil so that it can be pipelined to the market. Information from in-situ produced shale-oil experiments indicate that this upgrading may not be necessary for in-situ development. The addition of chemical flow improvers to reduce the viscosity has been considered as an alternative to upgrading.

Surface retorts utilize crushed oil shale from surface or underground mining. There are basically two types of surface retorts: direct heated and indirect heated. Most direct heated retorts are vertical gravity flow systems where air and oil shale are mixed in a retort chamber and the heat for pyrolysis is derived from combustion of a portion of the hydrocarbon

and residual carbon in the oil shale. This system exhibits poor heat control which causes sintering of the shale and limits the feed to plus 1/2-inch material. Pelletizing or briquetting of the fines (minus 1/2-inch material) prior to retorting has been considered as a solution to this problem. The indirect heated retorts use heat sources from outside the pyrolysis vessel for their operation. These are further divided into vertical gravity flow type systems which use hot recycle gas for a heat source, and systems which rely on heat transfer from externally heated solids. The vertical gravity flow systems generally are limited to coarse material while the solids heat transfer system will allow retorting of fine-sized feed material.

The principal surface retorting systems considered for early commercial use in the United States are the Gas Combustion retort, Paraho process, Union Oil Company retorts, TOSCO II retort, Lurgi-Ruhrgas process, Petrosix process, and McDowell-Wellman process.

The Gas Combustion retort (fig. 19) developed by the U.S. Bureau of

Figure 19. -- Near Here

Mines is a direct heated vertical gravity flow retort with countercurrent gas flow. Crushed shale (1/4-3 inches) enters the top of the retort and passes through the preheat zone where it is gradually heated to pyrolysis temperature by heat exchange with the hot product gas. Shale passes through the pyrolysis zone where oil and gas are liberated and carried

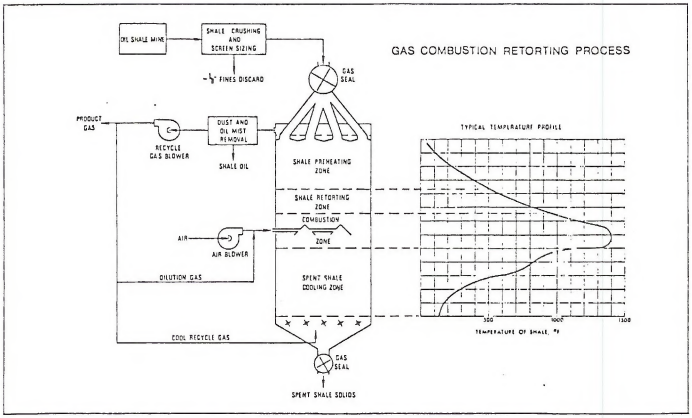


Figure 19. -- Gas combustion retorting process (Hendrickson, 1974).

upward and out of the retort with the combustion gas. The gas stream is split and some gas is recycled to the bottom of the retort. Retorted shale moves through the combustion zone where residual carbon is burned in a mixture of air and recycled product gas. The processed shale is cooled by the recycle gas and leaves the retort through a bottom discharge grate. Oil yields of 82 to 87 percent of Fischer assay have been reported for the process (Sladek, 1975).

The Paraho retort (fig. 20) is a modification of the gas combustion

Figure 20. -- Near Here

retort. This retort has been operated in direct and indirect heat configurations. Oil shale flows by gravity from the top to the bottom of the retort, while a countercurrent heat-carrier gas flows upward through the shale bed. Pyrolysis heat is generated by combustion of residual carbon and a portion of the product gas. The crushed (3/8-3 inches) raw shale feeding mechanism consists of a rotating spreader at the top of the retort. Temperature in the retort is controlled by adjusting the composition of the gas-air mixture feed to each set of burner bars in the retort and by adjusting the composition of the recycle gas. Processed shale exits the bottom of the retort through an oscillating discharge grate. Oil recoveries exceeding 90 percent of Fischer assay have been reported for the process (Sladek, 1975).

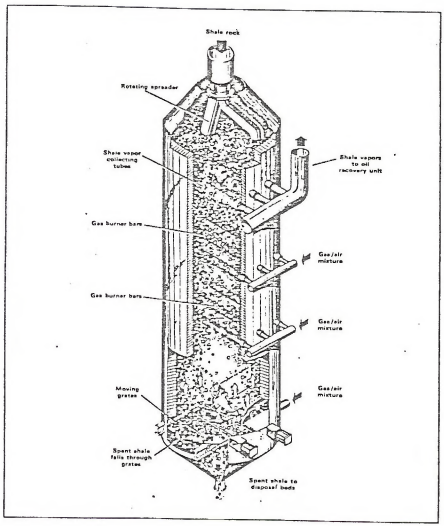


Figure 20. — Paraho retorting process (Hendrickson, 1974).

Union Oil Company retort designs include an "A" retort with internal combustion of residual carbon and gas, a "B" retort with external heating and recycling of the gaseous heat carrier, and a Steam-Gas Recirculation (SGR) retort (fig. 21) which generates heat in a separate vessel by gasification

Figure 21. -- Near Here

of residual carbon with oxygen and steam. Crushed shale (1/8-5 inches) enters through the base of the retort, travels upward and exits at the top. The countercurrent gaseous heat carrier enters the top of the retort and is pulled downward through the shale by suction blowers. Product oil flows down through the moving bed of shale and is collected at the bottom. A reciprocating piston ("rock pump") pushes shale up through the retort which mixes the shale and breaks up clinkers and gas channels. In the indirect heated SGR system, product gas from the retort is reheated in a recycle gas heater and returned to the retort. Retorted shale passes into a gasifier vessel in which residual carbon reacts with oxygen and steam to yield a synthesis gas. Some of the hot synthesis gas is used to generate steam and the remainder is mixed with recycle gas and injected into the retort. Oil recovery of 100 percent of Fischer assay has been reported for the SGR retorting system (Sladek, 1975).

The TOSCO II retort (fig. 22) is an indirect heated system which uses

Figure 22. -- Near Here

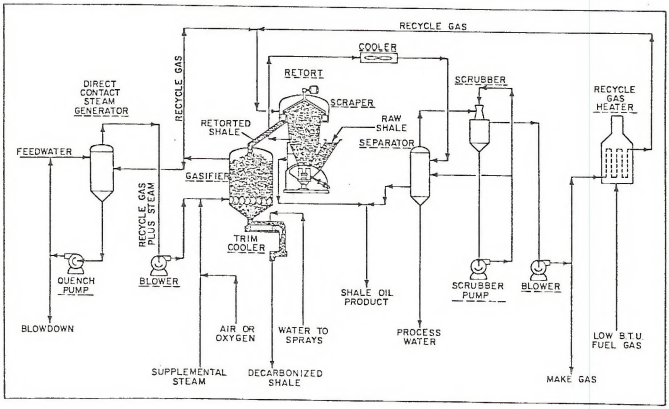


Figure 21. -- Union Oil Company steam-gas recirculation retorting system (Sladek, 1975).

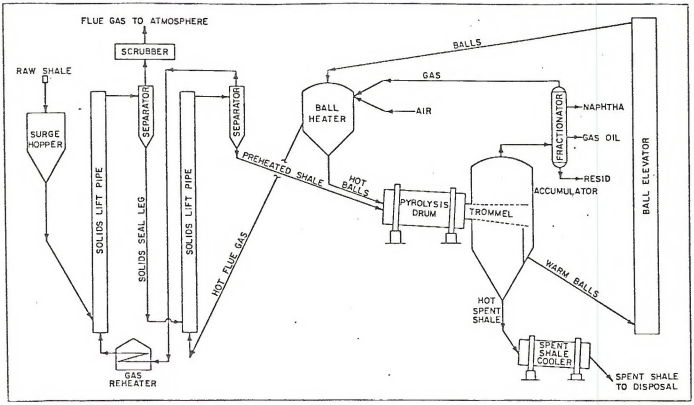


Figure 22. -- TOSCO II retorting system (Sladek, 1975).

hot ceramic balls to transfer heat to finely crushed shale. Preheated crushed (minus 1/2 inch) shale is fed to a rotating pyrolysis drum along with a separate stream of hot (about 1,200°F) ceramic balls. Retorting heat is transferred to the shale, and oil vapors and gas from pyrolysis are withdrawn. The ceramic balls and retorted shale are separated in a rotating trommel screen. The ceramic balls are reheated in a burning mixture of retort gas and air and returned to the pyrolysis drum. Liquid hydrocarbon recovery is about 99 percent of Fischer assay, and total recovery of C_4 and heavier hydrocarbons is about 108 percent of Fischer assay (Hendrickson, 1974).

The Lurgi-Ruhrgas (LR) process (fig. 23) is an indirect heated system

Figure 23. -- Near Here

which uses auger mixing to transfer heat from recycled processed shale. Sand has also been used as a supplemental heat carrier when retorting rich oil shale because rich shale tends to disintegrate to a fine powder during retorting. Finely crushed (minus 1/2 inch) raw shale is retorted in the mechanical mixer. A portion of the processed shale is recycled to a lift pipe where it is mixed with air and recycle gas resulting in combustion of the residual carbon on the processed shale. If residual carbon on the retorted shale is not sufficient for process heating, some fuel gas must also be added to the lift pipe. The combustion gases and hot solids are separated. The solids flow back into the mixer where they contact fresh

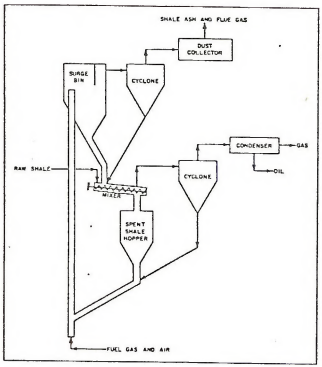


Figure 23. -- Lurgi-Ruhrgas process (Sladek, 1975).

oil shale and the cycle is completed. Maximum oil recovery of 102 percent of Fischer assay has been reported from pilot plant tests (Sladek, 1975).

The Petrosix process (fig. 24) is an indirect heated vertical gravity

Figure 24. -- Near Here

flow system which uses preheated recycle gas injected near the midpoint of the vessel as a heat source to retort the shale. The gravity flow retort is limited to coarse material -- particles as much as 6 inches in diameter. Retorting heat is supplied by a recycle stream of off-gas which is heated in a separate gas heating furnace designed to use either shale oil or process gas as fuel. Preheated recycle gas is injected into the bed of shale at the retorting zone level. An unheated recycle gas stream is injected into the lower part of the retort to ascend through the processed shale and recover heat. The retort design includes a unique feeding mechanism and a discharge grate to ensure uniform shale flow. No oil recovery yields have been released for the Petrosix process.

The McDowell-Wellman process, as proposed by the Superior Oil Company, is a direct heated type of retort that uses a horizontal rotating circular grate (fig. 25) to move the oil shale through the retorting sequence. This

Figure 25. -- Near Here

process has been specifically incorporated into the Superior Oil Company's multi-mineral (oil shale, nahcolite, and dawsonite) development. Three raw

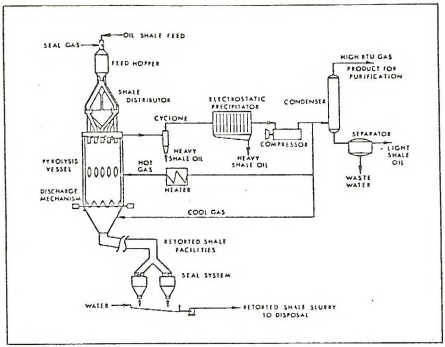
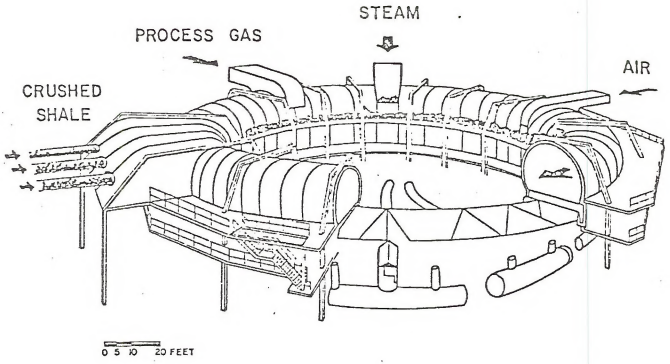


Figure 24. -- Petrosix process (Hendrickson, 1974).



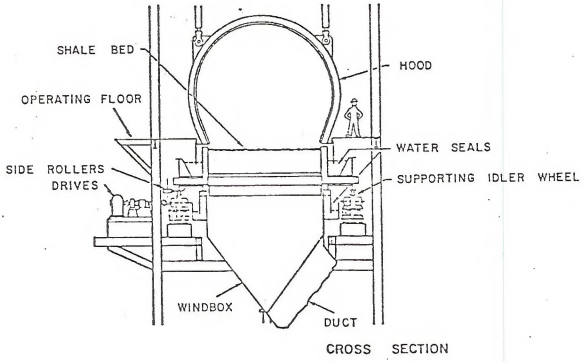


Figure 25. -- Circular retort with cross section (Superior Oil Company).

shale streams are fed to the circular retort. The finest material (1/4 - 1 inch) is laid down first on the grate, followed by the intermediate fraction (1 - 2 inches), and then the coarsest fraction (2 - 3 inches). The bed depth of shale is about 54 inches. The retort is divided into a loading zone, retorting zone, residual carbon recovery zone, cooling zone, and unloading zone. In the retorting zone, hot gases are drawn downward through the oil shale bed where they heat the shale to retorting temperature. The retorted shale is contacted with steam and air to form producer gas by reaction with the carbon residue. The horizontal grate and regulated airflows provide excellent temperature control. Oil recovery yields have not been published for this process.

In-situ retorting

In-situ retorting techniques include true in-situ and modified in-situ retorting systems. True in-situ retorting of oil shale is an alternative to mining and above-ground retorting. It eliminates material handling and the necessity for surface disposal of processed shale. The modified in-situ retorting concept is a system whereby underground in-situ rubble chambers are developed by conventional mining operations.

Oil-shale deposits considered suitable for true in-situ processing include low-grade deposits, thick deposits of deeply buried shales, shallow deposits, deeply buried leached shales, shales containing soluble minerals,

and thin beds at various depths interspersed with barren rock. True in-situ retorting can be divided into processes which use natural permeability and processes that create artificial permeability in the oil-shale deposit. Actual retorting uses a heat carrier to transfer retorting heat to the shale. The estimated oil recovery efficiency ranges from 55 to 70 percent (Morse, 1976).

Equity Oil Company has developed a true in-situ process for extraction of shale oil from the naturally permeable leached zone of the Green River Formation in the Piceance Creek basin. The process injects either hot natural gas or methane into the formation through an injection well. Gas flows through the natural permeable leach zone and heats the oil shale to retorting temperature. Shale oil, produced gas, and the injected gas flow to a production well and are pumped to the surface for separation. Gas is reheated on the surface and recycled through the injection well. Recovery rates are low because the injected gas and product oil tend to diffuse into the surrounding formation.

Various techniques have been proposed to create artificial permeability or fractures in underground oil-shale beds for true in-situ retorting. These methods include fracturing by high-pressure air and water, chemical explosives, nuclear devices, and electric current. Shell Oil Company has studied an in-situ process which creates artificial permeability within the saline mineral zone. Permeability is obtained by solution of the nahcolite to create void spaces and subsequent fracturing owing to collapse of the

formation. The usual approach to the above techniques has been to drill a pattern of production wells around a central injection well. The shale is fractured between the wells and hot gases or fluids are forced through the shale to retort the kerogen. Product oil and gases are pumped from the peripheral wells (fig. 26). Possible heat sources include combustion of

Figure 26. -- Near Here

in-place oil shale initiated by natural gas and sustained by air, hot natural gas or methane, hot carbon dioxide, superheated steam, hot solvents, or combinations of the above.

The modified in-situ retorting concept (figs. 27 and 28) involves removing,

Figure 27. -- Near Here

Figure 28. -- Near Here

by conventional mining, a portion of the oil-shale deposit to provide a void volume of 15 to 30 percent. The remaining shale within the interval to be retorted is rubblized into the mine voids by either explosive fracturing or sublevel caving methods to create a column of rubblized shale. For maximum retort efficiency, rubblizing must produce a sizing and distribution of porosity as uniform as possible. Combustion is initiated at the top of the rubblized shale column and progresses to the bottom with retorting taking place ahead of and below the combustion zone. Air, gas, and/or steam is injected at the top of the retort chamber and oil is withdrawn from a sump at the bottom. Commercial-sized retort chambers of from

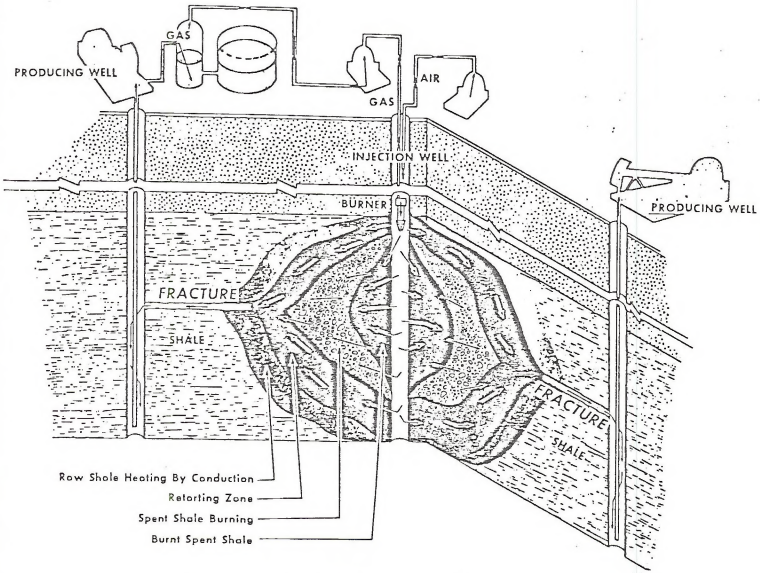


Figure 26. -- In-situ retorting of oil shale (Grant, 1964).

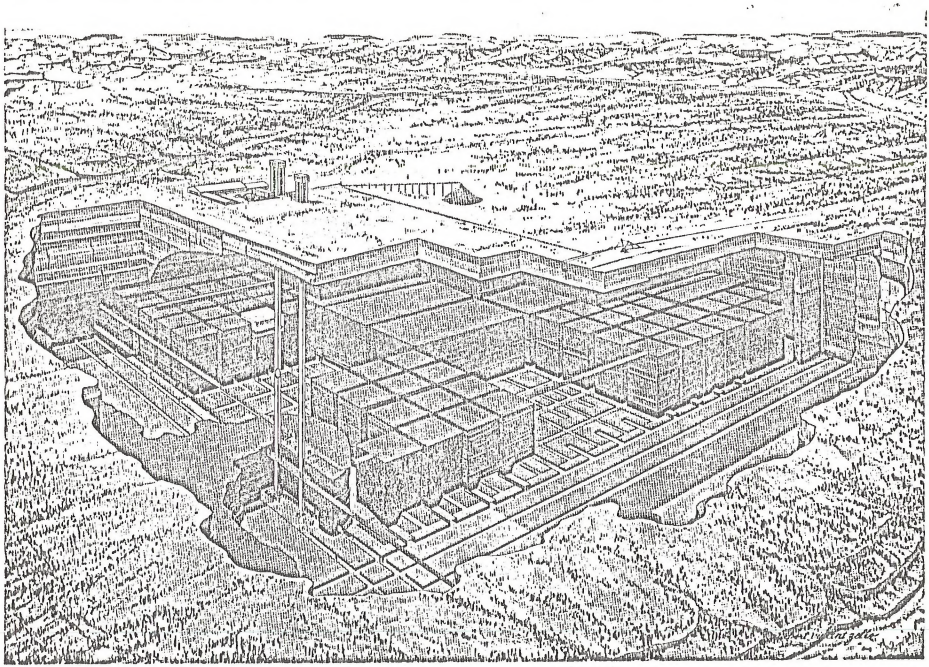


Figure 27. -- Artist's conception of modified in-situ development (Ashland Oil, Inc. and Occidental Oil Shale Inc., 1977).

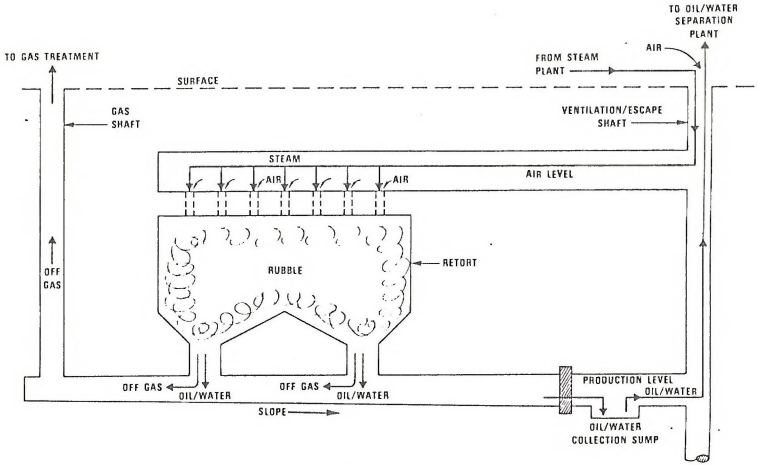


Figure 28. -- Modified in-situ retorting of oil shale (Ashland Oil, Inc. and Occidental Oil Shale Inc., 1977).

200 ft. x 200 ft. x 310 ft. to 150 ft. x 300 ft. x 750 ft. in height have been proposed (Ashland Oil, Inc. and Occidental Oil Shale Inc., 1977; and Gulf Oil Corporation and Standard Oil Company-Indiana, 1977).

There are several approaches to mining system design for modified in-situ retort development. Published areal extraction ratios for these methods range from about 45 percent to over 80 percent. Retorting efficiencies within the in-situ chambers have been reported as ranging from approximately 40 percent to almost 80 percent of Fischer assay.

Studies have shown that optimum resource recovery for modified in-situ development can be obtained when surface retorting of the mined shale is combined with in-situ retorting. This approach is most applicable to those deposits having rich oil-shale zones which can be removed for void volume development and retorted on the surface. The remaining section to be rubblized must contain an oil-shale grade suitable for in-situ retorting. However, where thick interbedded low-grade oil-shale zones are present, consideration should be given to developing void volumes in these zones, as the low-grade material may hinder passage of the flame front and reduce the retorting efficiency. This could result in low-grade material, unsuitable for surface retorting, being disposed of on the surface.

ECONOMICS

The value of recovered shale oil is determined by the economics of the shale-oil production facilities. The economics of oil-shale development is influenced by uncertain production costs, inflation, environmental protection and reclamation costs, governmental levies, future costs and quantities of other domestic fuels, and future costs and quantities of foreign crude oil. These factors increase the amount of the required capital investment and increase economic uncertainties.

The capital investments required for an oil-shale operation are directly affected by oil-shale grade, production rate, mining and/or rubblizing method, and type of retorting technique. As oil-shale grade increases, the amount of shale that must be mined and processed to produce a given quantity of shale oil decreases. Capital and operating costs also decrease significantly as the oil-shale grade increases. Table 4 presents estimated 1974

Table 4. -- Near Here

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capital and operating costs for six different oil-shale complexes. However, these cost estimates are already obsolete because of considerable inflation. For example, cost estimates for Colony Development Operation's underground room-and-pillar oil-shale mine and surface TOSCO II retort operation with a 55,000 barrel per day capacity for the period 1972 through 1975 have escalated as follows:

Table 4. -- Oil-shale complex capital and operating costs (1974 dollars).

[Data from Morse (1976). Mod IS, modified in-situ; S, surface; U, underground.]

MINE TYPE----------	Undrgnd	Mod IS	Mod IS	In-Situ	Undrgnd	Surface
RETORT TYPE----------	S	S & U	S & U	U	S	S
CAPACITY (BPD)----------	50,000	50,000	50,000	50,000	100,000	100,000
SHALE FEED GRADE (GPT)------	30	18	25	22	30	30
Capital Investment (millions of dollars)------	280	310	280	380	200	520
Operating Cost, excluding depreciation (millions of dollars per year)----------	45	110	90	140	45	80
Capital Cost per 1000 BPD CAP($)---------	5600	6200	5600	7600	5200	6000
Operating Cost per 1000 BPD CAP($)----------	2.46	6.03	4.93	7.67	2.19	2.19

Date of Estimate	Capital Cost (millions of dollars)	Operating Cost (dollars per barrel)
1972	255	1.82
March 1974	425	3.13
August 1974	653	4.30
September 1975	960	4.77

Capital investment for a similar facility in 1978 would probably exceed $1 billion.

The rate of return on an investment for a given oil-shale development is a function of the dollar value (selling price) of the shale-oil product. The shale-oil price and rate of return can be compared with the costs of imported oil and the controlled price of domestic oil to determine the profitability of an oil-shale project. Figure 29 depicts one estimate of

Figure 29. -- Near Here

the selling price for shale oil at different rates of return for a 50,000-barrel-per-day oil-shale facility. At a discounted cash-flow (DCF) rate of return of 15 percent, the value of a barrel of shale oil is indicated to be $12.70 (1975 dollars). This compares to the 1975 average U.S. crude oil price of $8.39 and a world oil price of $13.93 (Warren Mankin, oral commun., 1978).

Considerable savings are possible in producing a crude shale oil rather than a hydrotreated sulfur-free oil. An economic comparison was

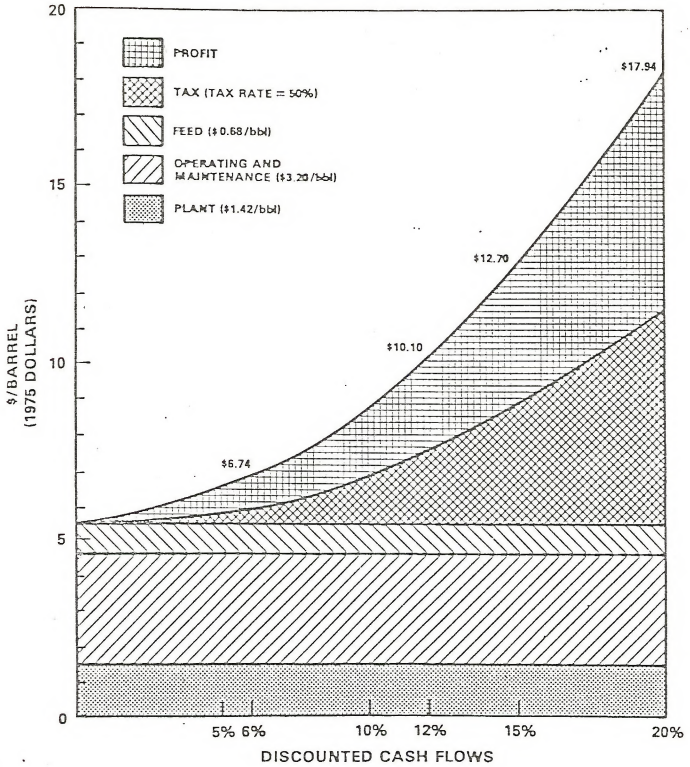

Figure 29. -- Oil-shale selling price for different cash flows (Johnson, 1976).

made of the Colony Development Operation's proposed facilities and the results are given below (Whitcombe and others, 1976):

Required selling price, $/bbl (September 1975 dollars)	Raw shale oil plant	Hydrotreated oil plant
For 10% DCF (Discounted cash flow)	$11.20	$14.20
For 13% DCF	14.20	18.30
For 15% DCF	16.70	21.70

The capital investment is reduced by approximately $160 million for the raw shale oil plant and direct operating costs are lowered by about $1 per barrel. Obviously the quality of the oil from the two plants is considerably different, and the hydrotreated oil merits a premium price over any crude shale oil. But even these prices, at a reasonable rate of return, exceed the 1975 world oil price of $13.93.

Studies indicate that modified in-situ systems combining underground mining, rubblization, and in-situ retorting of oil shale merit economic consideration. The economic feasibility is indicated by the selling price and rate of return for two selected mining systems for modified in-situ retort development (fig. 30). The room-and-pillar system is considered

Figure 30. -- Near Here

a first-generation design because it uses readily available equipment and

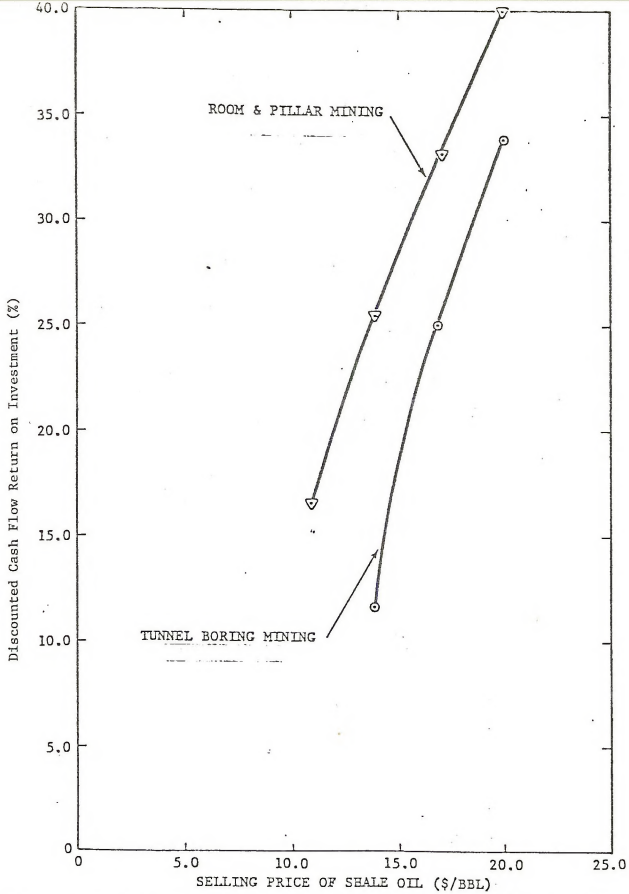

Figure 30. -- Cash flow versus selling price for two modified in-situ oil-shale mining systems (Fenix and Scisson, 1976).

proven techniques. The tunnel boring system is a second-generation design that uses techniques and equipment of higher productive capacity to enhance resource recovery. Both systems are based on a 50,000-barrel-per-day operation for oil shale averaging 20 gallons per ton at an in-situ retorting efficiency of 60 percent, to produce an unrefined shale oil for marketing. These factors indicate a selling price (1976 dollars) of about $10 per barrel for the room-and-pillar system to about $14 per barrel for the tunnel boring system, at a discounted cash flow return on investment of 15 percent. This compares to the 1976 average U.S. crude oil price of $8.84 and a world oil price of $13.48 (Warren Mankin, oral commun., 1978). Combining the modified in-situ process with surface retorting of the development rock can improve the economics by a savings of about 40 percent in operating costs and 25 percent in capital costs per barrel (Fenix and Scisson, 1976). Locating the mining level in the higher grade shale will provide the greater economic advantage owing to the higher retorting efficiency of the surface retorting process.

The relation of discounted cash flow return on investment (DCFROI) to Fischer assay for various selling prices (1976 dollars) for four underground mining systems is presented in figures 31 through 34. The mining

Figure 31. -- Near Here

Figure 32. -- Near Here

Figure 33. -- Near Here

Figure 34. -- Near Here

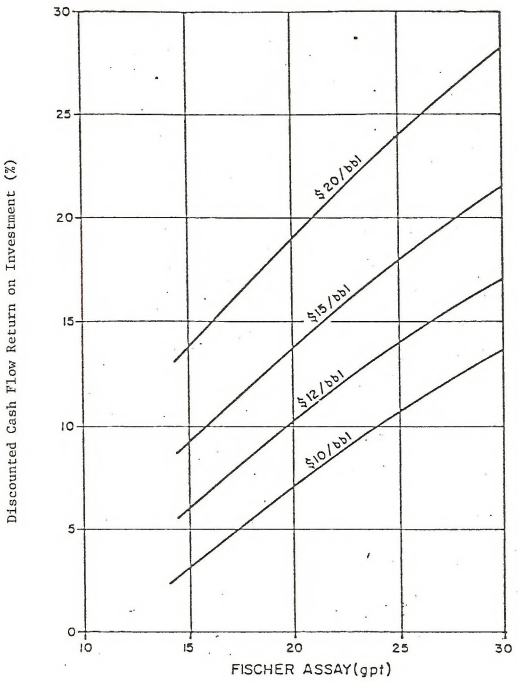

Figure 31. -- Cash flow versus selling price for various grades of oil shale: chamber-and-pillar mining (Cameron Engineers, 1976).

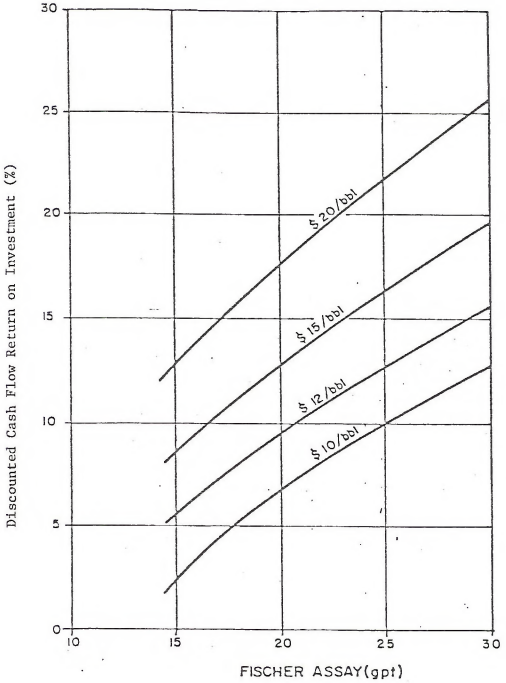

Figure 32. -- Cash flow versus selling price for various grades of oil shale: sublevel stoping with spent shale backfill (Cameron Engineers, 1976).

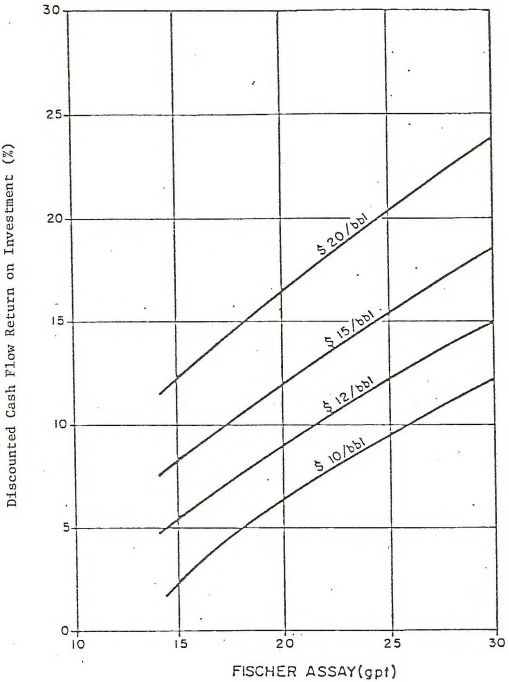

Figure 33. -- Cash flow versus selling price for various grades of oil shale: sublevel stoping with full subsidence (Cameron Engineers, 1976).

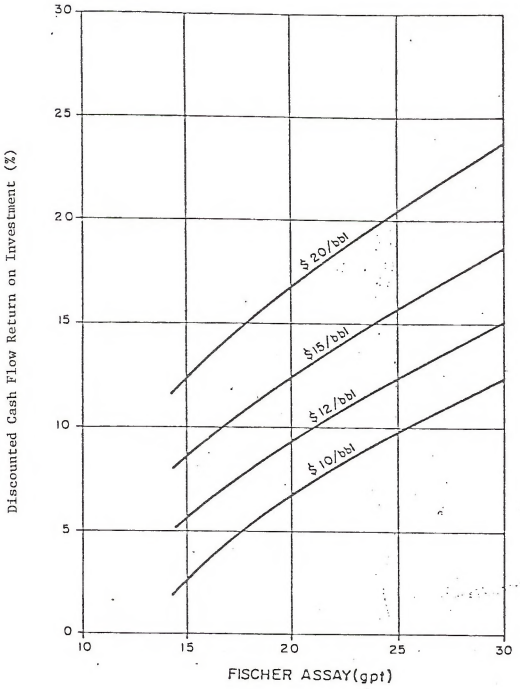

Figure 34. -- Cash flow versus selling price for various grades of oil shale: block caving (Cameron Engineers, 1976).

systems are chamber-and-pillar, sublevel stoping with backfill, sublevel stoping with subsidence, and block caving. Daily production is assumed to be 85,000 tons per day (50,000 barrels per day for 25 gpt shale) for each mining system. The product is a partially refined shale oil from the gas combustion retorting process (95 percent retort efficiency). Evaluation of this information indicates a selling price (1976 dollars) of $13 to $15 per barrel for the four mining systems at a discounted cash flow return on investment of 15 percent and an average oil-shale grade of 25 gallons per ton. This again compares to the 1976 average U.S. crude oil price of $8.84 and a world oil price of $13.48.

World oil prices have risen to a 1977 average of $14.50 per barrel and domestic oil prices to an average of $9.48 per barrel (Warren Mankin, oral commun., 1978). The June 1978 domestic crude upper tier price controlled by the Economic Regulatory Administration is $12.72. The Federal Energy Administration ruled (ruling 1976-4), effective June 17, 1976, that synthetic crude oil obtained from oil shale did not fall within FEA's authority to establish mandatory petroleum allocations and price regulations under the Emergency Petroleum Allocation Act of 1973. In effect, this entitles shale-oil producers to receive the world price of oil. This position was supported by the President's Energy Program presented to a joint session of Congress on April 20, 1977. The program states that "because of the high risks and costs involved in shale oil development, shale oil will be entitled to receive the world price of oil in the United States."

A new Department of Energy rule, effective July 1, 1978, also provides about a $2-per-barrel subsidy to domestic refiners that produce petroleum products from oil shale and other synthetic fuels. This ruling, under the entitlements program of the Economic Regulatory Administration, will enable oil shale and other synthetic fuels to compete effectively with imported crude oil. Under the rule, shale oil used in refineries will automatically qualify for the entitlements benefits.

To stimulate private shale-oil development, the Congress considered in 1977 and 1978 an amendment to the Energy Production and Conservation Tax Incentive Act (H.R. 5263) that would allow a $3 tax credit for each barrel of shale oil produced. The amendment passed the Senate Finance Committee by a two-to-one margin prior to further action by a House-Senate Conference Committee. The proposal provides a direct and effective means for stimulating construction of initial oil-shale plants and for resolving the uncertainties and economic risks of such projects.

In summary, it appears that an oil-shale industry can be economical at the current world price of oil and that any incentive that reduces the uncertainties and economic risks involved will serve to further stimulate development. At a 15 percent rate of return, the selling price (1976 dollars) of shale oil for various mining and retorting systems discussed, ranged from $10 to $15. This is compared to the 1977 average world oil price of $14.50 per barrel, which shale oil is entitled to receive. The world price of oil can be considered as the maximum market value for a commercially produced barrel of shale oil. Therefore, this price can be used to determine the value of an oil-shale property.

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